Analytic Approaches for Projecting CO_2 Emissions from Affected EGUs: Key Input Assumptions that Drive Modeling Projections

TSD – Projecting EGU CO2 Emissions Performance: Mass-Based Goals and Plan Performance

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Key Input Assumptions that Drive Modeling Projections

Both utility-scale capacity expansion models and simulation dispatch models are industry-standard tools. While the model structures, particularly those that have been vetted in regulatory review, are generally viewed as credible, results of these tools are sensitive to key input assumptions. In particular, evaluating changes in emissions due to emissions reductions polices is sensitive to assumptions that impact EGU on the operational and build margins. Assumptions that impact economic dispatch decisions and retirement/new build decisions can substantively impact the outcome of marginal analyses. For example, an assumption that forward-looking natural gas prices are relatively high may result in a finding that EE/RE displace gas resources, while an assumption that gas prices are relatively low may result in a mixture of coal and gas on the margin; variance in this assumption could drive different policies and policy expectations.

U.S. EPA has documented their key input assumptions in their EPA Base Case v.5.13.1 This serves as the starting point against which policy scenarios may be compared. EPA's Base Case v.5.13 is a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2013.

Load Forecast

The load (or demand) forecast is an estimate of the peak (MW) and gross energy (GWh) requirements of electricity consumers, prior to the application of incremental energy efficiency or other demand-side measures (DSM). The load forecast should represent a business-as-usual or reference case scenario from which incremental load reduction measures will be decremented. Near-term and long-term load forecasts provide the basis on which decisions for new capacity (or the ability to retire non-economic capacity) are made for utilities and balancing areas. The load forecast will directly affect the marginal emissions rate of the system by determining how many units must be brought online to meet load.

Under an emissions rate approach, establishing a sound and valid load forecast may be one of the single most important elements in ensuring sound policy, accomplishing real reductions, and allowing for a reasonable assessment of the impacts of emissions reductions policies.[2]

There are many types of detailed load forecasting methods used, from simple extrapolation from

[1] For more details, see EPA's Power Sector Modeling Platform."
http://www.epa.gov/powersectormodeling/BaseCasev513.html

[2] If the success of an emissions reduction policy is assessed against a reference case (i.e. without the policy in place) rather than as an absolute mass-based target, establishing a reference case becomes the key metric against which any policy is measured. To the extent that load reduction measures (such as EE or RE) are used to meet relative emissions reductions, these load reductions will be assessed against a reference case. A reference case that overestimates load growth will result in fewer real emissions reductions, while a reference case that envisions lower growth than reality will require deeper reductions than required by policy.

historic time-series, to end-use and/or economic models. [3] Load forecasts are typically exogenous to electric sector modeling (i.e. they are considered an input) with the exception of multi-sectoral models that may allow load requirements to be driven by macroeconomic feedbacks.[4]

- Time-series methods extrapolate past trends in annual growth and seasonal variation to develop a forecast. While these methods are fairly simple, they cannot anticipate the impact of macroeconomic and policy changes that drive demand.[5]
- End-use models anticipate customer demand in particular classes (i.e. large industrial, small industrial, commercial, agricultural, municipal, residential) or even subclasses based on equipment needs, technology changes, and macroeconomic trends, but require calibration.
- Econometric models compare historic energy consumption against energy price, economic, census, and climate data to derive underlying forcing factors and arrive at a more detailed forecast, but require substantial time to develop and may not capture trends not reflected in the historic record. [7]

EPA uses regional forecasts of peak and total electricity demand from AEO 2013 for EPA Base Case v5.13 and uses hourly load curves from FERC Form 714 and ISO/RTOs (2011 for EPA Base Case v5.13) to derive future seasonal load duration curves for each IPM run year in each IPM region. EIA provides regional load forecasts from the Annual Energy Outlook model runs, based on detailed feedback modeling. Individual regional transmission organizations (RTOs) and independent system operators (ISOs) generate their own load forecasts to estimate future transmission and reliability requirements. The North American Electric Reliability Council (NERC) generates load forecasts to review impending reliability issues. Finally, individual load serving entities (LSEs, i.e. utilities) generate their own load forecasts to predict future requirements. In all cases, load forecasts should be carefully characterized for if they incorporate existing or "on the books" DSM measures. EIA Form 861 maintains LSE-specific and sector differentiated historic annual load.[8] FERC Form 714 maintains historic hourly load requirements for various LSEs, aggregate utility companies, and selected RTOs. ISOs maintain records of historic hourly load profiles, in some cases differentiated at the regional hub scale.

Fuel Costs

The dispatch of power plants is highly sensitive to fuel price forecasts. Fuel prices represent an

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[3] For more details, see "Assessing the Multiple Benefits of Clean Energy: A Resource for States". US EPA-430-R-11-014. September 2011.

[4] One such example is the National Energy Modeling System (NEMS) used in EIA's Annual Energy Outlook. This model considers sectoral impacts of fuel prices, emissions policies, and technology costs on different sector energy requirements. See http://www.eia.gov/forecasts/aeo/er/index.cfm.

[5] For example, extrapolating a time series from past demand in 2011 would have significantly overestimated growth due to the economic downturn.

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[8] http://www.eia.gov/electricity/data/eia861/

important, if not primary, component of the overall cost of generation for facilities using gas, coal, or biomass, and the relative cost of different fuels will be a deciding factor in the determination of the order in which EGUs are dispatched, the marginal source of supply and thus marginal emissions (i.e. emissions displaceable through load reduction measures). Fuel prices are function of resource supply, delivery constraints, and demand regionally, nationally, and internationally.

Near term fuel price forecasts may take into account market data based on current futures prices, however these are typically only useful a few years into the future.[9] Longer term forecasting typically incorporates historic trends as well as resource supply characteristics, technology improvement, and anticipated demand. Typically, forecast fuel prices are generated with the use of a mutli-sector model.[10] Fuel prices may also vary significantly by region, depending on proximity to sources (wells or mines), transportation costs, and regional demand. For most electric sector modeling applications, fuel prices are considered an exogenous input.

EPA represents fuel price and supply in EPA Base Case v.5.13 in one of three alternative ways: (1) through an embedded modeling capability that dynamically balances supply and demand to arrive at fuel prices (natural gas), (2) through a set of supply curves (coal and biomass) or (3) through an exogenous price stream (fuel oil and nuclear fuel). EIA calculates fuel prices endogenously within NEMS in modules representing the supply and demand for coal,[11] gas,[12] other fuels based on detailed feedback modeling; the fuel price outcomes of these model runs are available on a regional basis. [13][14]Industry research groups also provide proprietary fuel price forecasts. Utilities will either develop their own forecasts, or rely on one or more government or industry research forecasts to develop their own assumptions. Historic fuel prices are collected by EIA, and available on a plant-by-plant basis from EIA's Form 923.[15]

Existing Supply-Side Resources

Estimates of the impacts of nearly all emissions reductions policies hinge on the disposition, cost, emissions, and fate of existing EGU. In particular, existing EGU close to the operational margin or build margin (i.e. possibly non-economic) will be the units most impacted by unit efficiency improvements, emissions markets, load reduction measures, and increasing penetration of renewable energy. Variable operating costs are key to short-term simulation dispatch models, while both variable and fixed costs impact decisions in long-term capacity expansion planning models.

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[9] In fuel futures markets, trading volume declines significantly after two to three years, meaning that fewer traders have assessed future price outcomes.

[10] For example, EIA's Annual Energy Outlook assesses national and international demand for fuels, evaluates supply options, and estimates fuel prices accordingly.

[11] EIA AEO 2013. Coal Market Module. http://www.eia.gov/forecasts/aeo/assumptions/pdf/coal.pdf

[12] EIA AEO 2013. Gas and Oil Supply Module. http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf; Natural Gas Transmission and Distribution Module.http://www.eia.gov/forecasts/aeo/assumptions/pdf/natgas.pdf

[13]

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[15] See http://www.eia.gov/electricity/data/eia923/

Over the short term, variable costs determine the operations of a unit; thus heat rate and variable operations and maintenance (O&M) costs, including chemical and sorbent costs, are key in the determination of the operational margin.

Over the longer term, the utilities and EGU owners determine if it is economic to continue operating existing EGUs by reviewing their forward-looking revenues against costs. Units that are more expensive to operate over the long-term than maintain should be considered for economic retirement. Forward-looking costs include fixed O&M, ongoing capital costs for regular maintenance and incremental environmental compliance, and decommissioning costs. Long term plans should consider the variable and fixed cost implications of both promulgated as well as reasonably expected regulations to gauge cost and risk. In addition, the discount rate employed by a utility (the weighted average cost of capital, or the cost of their debt service), may critically impact decisions that the utility makes about short and long-term investments.

EPA's Base Case v.5.13 uses the NEEDS database as its source for data on all existing and planned committed units. NEEDS v.5.13 uses EIA Form 860 data as one of the primary generator data inputs of existing unit population. [17] EIA Form 860 is an annual survey of utility and non-utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), operating status, prime mover, energy sources and in-service date of existing and proposed generators. The form also maintains data on environmental controls types and efficacy, as well as waste disposal costs.[18] EPA's Air Markets Program Data (AMPD) can be used to derive emissions rates for CO2, NOx, and SO_2 for individual boilers.[19][20]

Operational and cost data for individual EGUs are often considered confidential business information (CBI) by utilities and independent power producers. Industry research groups estimate cost and operational data for individual EGU, based on market research, assessment of physical infrastructure, and publicly available operational information; this information is often also considered proprietary. The EIA and other government research groups (including EPA's IPM Base Case) maintain generic assumptions about the operational cost of existing EGUs.[21] Capital and operational costs for environmental controls are also maintained by many utilities; however, third parties and EPA have developed estimates for controls for regulatory purposes (EPA IPM Base Case). Fixed O&M, maintenance capital, and decommissioning costs are often EGU specific (and thus considered CBI), but 3rd parties have developed and maintain estimates for these costs. Finally, similarly to existing supply-side resources, the discount rate employed by a utility may critically impact decisions that the utility makes about short and long-term investments.

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17 For more details visit EPA's Power Sector modeling documentation Chapter 4. http://www.epa.gov/powersectormodeling/docs/v513/Chapter_4.pdf

18 http://www.eia.gov/electricity/data/eia860/

19 http://ampd.epa.gov/ampd/

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21 http://www.epa.gov/powersectormodeling/docs/v513/Chapter_4.pdf

New Supply and Demand-Side Resources

Long-term modeling efforts that review changes on the build margin require detailed inputs for the costs of new supply and demand-side resources.[22] A number of economic and operational factors contribute to the decision of what type of new resource will be built to meet load and/or replace retiring units.

New resource information for supply-side resources includes capital costs, fixed and variable operations & maintenance, and heat rates. The EIA calculates aggregate average parameters for these factors in the AEO.[23] Utilities and third parties may do more detailed analysis considering site-specific requirements; some of these estimates are considered proprietary or CBI. Other utilities publish their expectations of new resource costs and operational constraints in planning assessments.[24] Detailed cost, availability and operational information on renewable resources are maintained by the National Renewable Energy Laboratories. Solar and wind resources require additional information on the seasonal or hourly load impact profile to assess under which circumstances these units could or should be expected to reduce demand for fossil resources. All new resources should account for interconnection costs, while wind and solar resource may need to also account for the integration costs including transmission charges and – depending on the model – the costs to meet rapid swings in supply or forecast errors.

Demand-side resources are often characterized by cost, ramp rate, availability and expected resource life. Numerous utilities and state entities have performed (and continue to perform) energy efficiency potential studies that characterize key assumptions about the cost and availability of demand-side resources. In addition, the American Council for an Energy-Efficient Economy (ACEEE) provides multiple state and regionally aggregated potential studies.

In some cases, utilities or ISOs may have a determination on the EGU that need to be added to their system in the reference case, or even under a carbon reduction regime. To the extent that the input assumptions used by individual energy entities are consistent with state policies and assumptions, these entities assumptions may be transferable to state plans to assess capacity expansion without the use of an explicit capacity expansion model.

[22] Capacity expansion planning models estimate how existing and new EGU meet demand requirements, and choose least cost new supply and demand-side resources to meet load. Simulation dispatch models typically review how a static fleet of EGU responds on an hourly (or finer) basis to demand requirements using security constrained economic dispatch.

[23] Table 8.2 in AEO's Electricity Market Module. See http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf

[24] See, for example, PacifiCorp 2013 IRP, Tables 6.1 and 6.2. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacifiCorp-2013IRP_Vol1-Main_4-30-13.pdf